DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

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IN THE MATTER OF NorthWestern Energy’s	)	
Application for Approval to Purchase and Operate	)	REGULATORY DIVISION
PPL Montana's Hydroelectric Facilities, for	)	
Approval of Inclusion of Generation Asset Cost	)	
Of Service in Electricity Supply Rates, for Approval	)	DOCKET NO. D2013.12.85
Of Issuance of Securities to Complete the	)	
Purchase, and for Related Relief	)	

Response Testimony of

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on behalf of

Human Resource Council, District XI
Natural Resources Defense Council

May 2014

Introduction and Summary

Q. Please state your name and occupation.

A. My name is Thomas Michael Power. I am a Research Professor and Professor Emeritus in the Economics Department at The University of Montana, Missoula, Montana. I am appearing in these proceedings, however, as an independent consulting economist, a principal in Power Consulting Inc., on behalf of Human Resource Council, District XI, and the Natural Resources Defense Council.

Q. Are you the same Thomas Michael Power who filed direct testimony in this docket?

A. Yes I am.

Q. What issues will you address in this response testimony?

A. I will address five important points where I disagree with Montana Consumer Counsel witness, Dr. Wilson.

1. Dr. Wilson uses the cost of electric market purchases as his reference point for evaluating NorthWestern Energy's (NWE) proposed purchase of the hydros. In his analysis he assumes that those future electric market prices are known and there is not risk associated with heavily relying on that market. This distorts his analysis of NWE's electric supply choices.
2. Dr. Wilson concludes that NWE's proposed purchase of the hydros would force customers to pre-pay hundreds of millions of dollars in speculative "carbon taxes" that may never be levied. This mischaracterization of the investment in the hydros could be applied to any electric supply choice that NWE might make. It is a rhetorical device, not economic analysis.
3. Dr. Wilson implies that NWE's Discounted Cash Flow model (DCF) was the sole analytical tool that NWE used to determine the $900 million price NWE offered PPLM for the hydros. This is a gross oversimplification of the suite of

analytical tools NWE used to analyze the economic logic of the purchase of the hydros.

4. Dr. Wilson runs together depreciation, salvage value, and the residual value of plant that still exists at the end of an arbitrary time period chosen for analysis. This confuses the discussion.
5. Dr. Wilson suggests that NWE may have increased the price it offered to PPLM for the hydros in order to create a huge profit windfall for NWE's stockholders at the expense of customers. His characterization of the role of investment and a market return to investors is entirely negative and could be applied to any long-run investment by any company. Investors, in general, are not the enemy of consumers.

1. Using market electric prices as the reference point in comparing resources

Q. What reference point does Dr. Wilson use to judge the economic logic of NWE's proposed hydro purchases?

A. Dr. Wilson exclusively uses regional market prices as the reference point. If the revenue requirements associated with meeting load with the proposed hydro purchase are higher than purchasing that electricity on the regional market, he interprets that as evidence that customers are being burdened with an unnecessarily costly source of supply. See, for instance, Dr. Wilson's conclusions, p. 59 at line 16 and 60 at line 8.

Q. How do we know what future regional electric prices will be so that that comparison can be made?

A. We do not know what they will be. Dr. Wilson uses NWE's *projections* of future electric market prices (without any projected carbon cost adder). NWE's projected electric market prices are based on Mid-Columbia (Mid-C) future price strips going out a half-dozen years and an assumed growth rate in market electric prices after that.

Q. Is there uncertainty about future electric market prices?

A. Certainly.

There is a monthly pattern of movement of those market prices across the year because of the heavy hydroelectric production during spring and early summer when the snowpack is melting. Fluctuations across the year in wind electric generation add another variable element into electric supply. In addition the demand for electricity varies across the year depending on fluctuations in weather than can lead to higher or lower heating and air conditioning loads.

In addition, there are also fluctuations in market electric prices across the years. There can be excursions in market prices that lead to very high prices that can last for months or years. Similarly there can be extended periods when market electric prices are quite low. Some of this fluctuation is tied to fluctuating natural gas prices since the cost of operating a natural gas fueled generator often sets the electric market price in the Pacific Northwest.

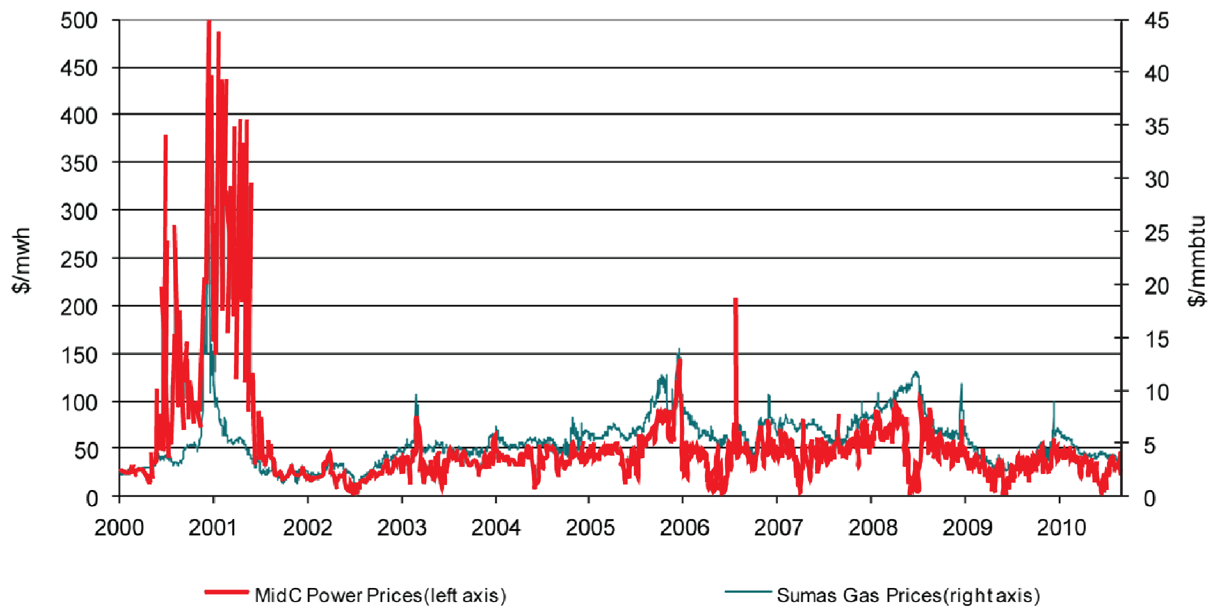
The figure below shows the fluctuations in Mid-C electricity market prices from the last decade (2000-2010). From 2010 through the middle of 2012, Mid-C prices continued to decline. In June and July of 2012 they were close to zero but then rose back to the $25 to $40 per MWh range during 2013.

The Northwest Power and Conservation Council (NPCC) described the instability in the regional electric market in its Sixth Power Plan in the following terms:

> Disequilibrium between supply and demand is commonplace for electricity markets. Disequilibrium results from less-than-perfect

foresight about supply and demand, inactivity due to prior surplus, overreaction to prior shortages, and other factors. Periods of disequilibrium can last years. The resulting excursions from equilibrium prices can be large relative to the routine variation due to temperatures, fuel prices, plant outages, and hydro generation. These excursions are a significant source of uncertainty to electric power market participants, and they are therefore an important part of the Council's scenario analysis. (p. 9-12)

Historical Daily Mid-C Power Price and Sumas Gas Price



Source: Puget Sound Energy 2013 Integrated Resource Plan, Appendix K, Figure K-5, page K-13

It is partially to avoid these costs associated with such upward excursions of regional electric prices that lead electric utilities to make investments in generation rather than rely primarily on the regional electric market to supply their customers. Again the NPCC's Sixth Power Plan described this in the following terms: (p. 9-10)

> The average cost of the low-risk portfolio will be slightly higher, but it provides protection, similar to an insurance policy, against the most costly future events…..
>
> Other evidence of reduced risk is reduced rate volatility and reduced exposure to the wholesale power market during high-price excursions…..
>
> In general, portfolios near the lower-risk end of the efficiency frontier contain more resources and rely less on the wholesale power market. By building more resources and reducing price volatility, these low-risk portfolios are more consistent with regulatory preferences and utility planning criteria than the lower-cost but higher-risk portfolios.

Q. Did Dr. Wilson take into account this uncertainty and volatility of regional electric prices in his direct testimony?

A. No. He chose to primarily use a <u>deterministic</u> discounted cash flow (DCF) model for most of his discussion. The word "deterministic" refers to the fact that this approach assumes that future values of various variables are known with certainty, i.e. there is no uncertainty about them. The market electric prices used by Dr. Wilson are those presented by NWE before carbon costs were added. These projected future market electric prices stretch across a 30-year period in a relatively smooth line. See the figure below.

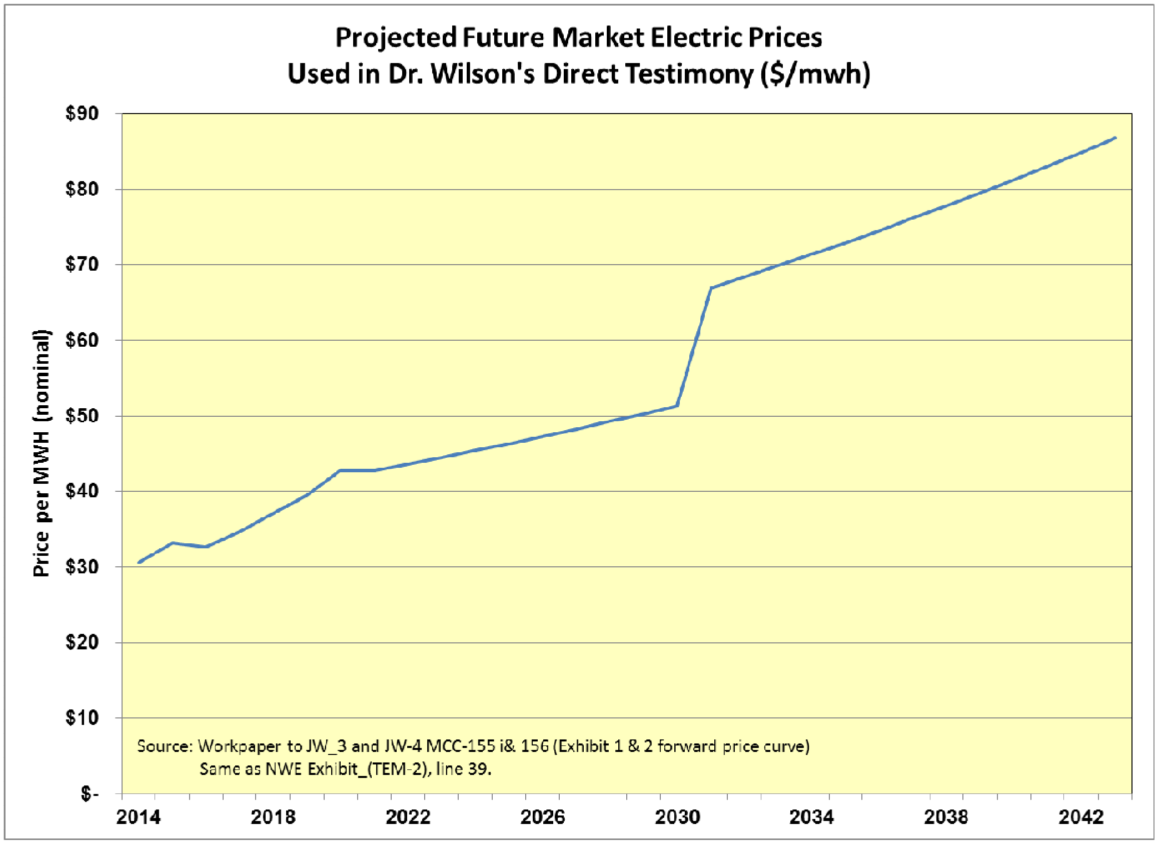


Chart 1, Tab GHG15 Forwords, Workpaper to JW-3 and JW-4….xlsx

Q. Why are you concerned about Dr. Wilson's assumption that future electric market prices are known?

A. One of purposes of utility Integrated Resource Planning (IRP) is to explicitly take into account the uncertainty and risk associated with many variables that determine the economic environment in which the utility will be operating in the future. Doing the resource procurement analysis in a way that directly confronts the major sources of risk allows the utility to take actions to reduce that risk and the costs associated with it.

Analyzing electric market risk is part of that planning exercise. If one does the analysis assuming that there is no market risk, that assumption will preclude analyzing resource procurement strategies that can reduce part of that electric market risk. That risk is simply eliminated by assumption. That is not useful analysis.

In particular, as the quote above from the NPCC's Sixth Plan makes clear, electric utilities often build their own electric generating facilities or contract long-term with limits on price escalation for electricity so that they can reduce electric market risk. Some additional cost is incurred as an insurance policy of sorts against that risk.

By assuming that the future market price of electricity was known and could be used to evaluate alternative sources of supply besides electric market purchases, Dr. Wilson is assuming away an important problem and decision with which electric utilities must wrestle.

Q. Are you saying that Dr. Wilson is over-simplifying the complexity of the supply decisions electric utilities have to make?

A. Yes, in two ways. First, as discussed above, he assumes that we know what future electric market prices will be. Second, he assumes that the obligation to customers that regulated utilities have is simply "obtaining electric power at the lowest cost." (Response to PSC-203a data request.) This sweeps away the broad set of objectives that utilities seek to take into account in their integrated resource planning, including uncertainty and risk.

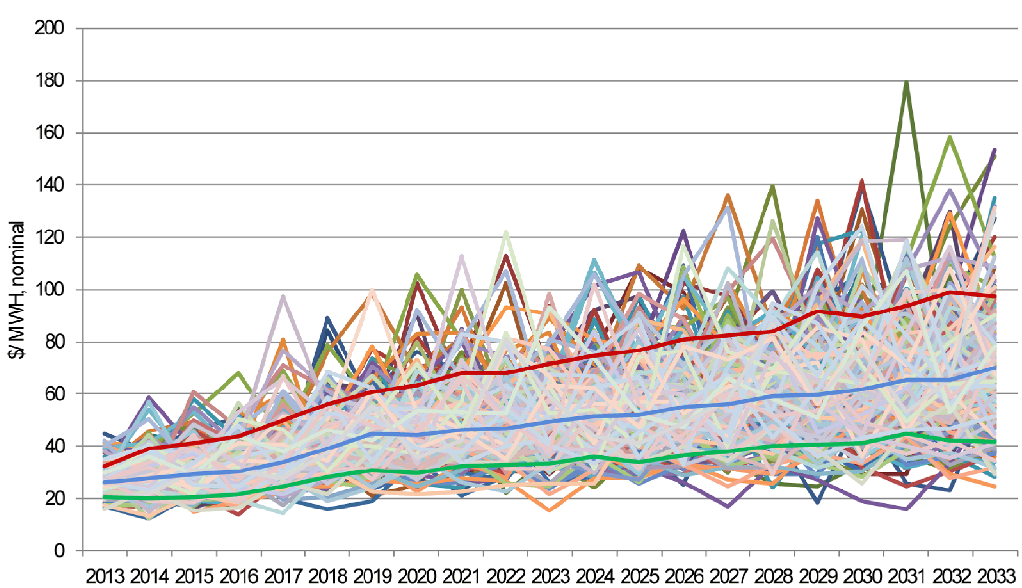
Q. How does the electric market price curve Dr. Wilson used compare to actual utility experience in the Pacific Northwest?

A. One can compare Dr. Wilson's price curve over a thirty-year time period shown on page 6 to the ten-year actual Mid-C price curve shown on page 4. Actual Mid-C prices varied from hundreds of dollars per MWh to zero with many excursions above $50 per MWh. Stochastic analysis of electric supply alternatives takes into account this uncertainty about future market electric prices as well as the instability in natural gas and coal prices, weather, etc. Standard practice in electric utility IRP processes now focuses considerable attention on analytical tools that explicitly incorporate that uncertainty.

Q. Can you provide a measure of the extent of the uncertainty about future electric market prices in the Pacific Northwest used by regional utilities in their IRP processes?

A. Yes. Stochastic modeling of resource selection in the context of uncertainty, uses past experience with market price variability adjusted for current knowledge to establish a frequency distribution of potential future outcomes. The distribution of all of those possible outcomes provides an indication of how different actual outcomes might be when compared to a simple deterministic assumption of what the market electric price will be in any given future year such as Dr. Wilson uses.

Annual Mid-C Price Draws with no Risks of CO_2 Cost/Price Policy



Source: Puget Sound Energy, 2013 IRP, Figure K-9, Appendix K, p. K-16

When looked at in this way, future electric prices do not look anything like Dr. Wilson's simple price curve on page 6. I have not seen the Monte Carlo market electric price draws associated with the Ascend's PowerSimm stochastic modeling for NWE's 2013 Electric Supply Resource Procurement Plan. However, Puget Sound Energy depicted the uncertain nature of future Mid-C electric prices in Puget's 2013 IRP. That figure is show above.

Note the very broad band of uncertainty about future electric market prices. It is this potential market price volatility that leads most regional electric utilities to use the regional electric market as a supplement to the electric resource portfolio that they develop to meet their customers' electric demands. When prices are right, they can use the market to sell excess generation to earn revenue that can be credited against their generation costs or back down their own generators and buy electricity more cheaply in the market, again reducing the costs that their customers otherwise would face.

The NPCC in its Sixth Plan developed a similar figure showing the broad uncertainty about future regional electric market prices. See Figure 9-3, p. 9-12 of the Sixth Plan.

The upper and lower solid lines on the figure above show the 10 and 90 percentile bounds that exclude high and low market prices that have less than a 10 percent chance of occurring. The center solid line is the "base" or median value. Dr. Wilson may see the electric market price curve that he used as representing such an "expected" future electric price curve. But, as the figure on page 8 makes clear, the electric market is much more risky than that, and electric utilities need to adopt strategies to manage that risk. They cannot afford to ignore it. Managing that electric market risk for their customers may well cost something, as any "insurance" strategy does. The cost incurred, however, cannot be asserted to be irrational or imprudent simply because electric supply costs may, at times, appear to be above the costs associated with simply making market purchases. One has to focus on the risk-cost problem the utility is trying to solve and evaluate whether the utility has managed that risk in a cost-effective way as Commission planning guideline require.

Simply assuming away the uncertainty and acting as if we *know* what future electric prices will be may be useful as a rhetorical device, but it is not useful in making rational electric supply decisions.

Q. You criticize Dr. Wilson for using electric market purchases as the reference point in analyzing alternative electric supply resources. But is it not true, as Dr. Wilson has said in his response to PSC 229(a) that: "[a]lternative market purchases are a benchmark that NWE chose to use and rely upon in both its comparative cost and valuation analyses?"

A. It <u>is</u> true the NWE included in the alternative electric supply portfolios a portfolio built around meeting all future supply needs through market purchases. That was <u>one</u> of the alternatives analyzed. It was not the benchmark of the analysis. One could, for instance, compare the hydro purchase against the natural gas fueled combined cycle combustion turbine (CCCT) alternative. It is Dr. Wilson who made it the "benchmark" in his analysis.

2. Making Customers "Prepay" a Hypothetical Carbon Tax

Q. How does Dr. Wilson characterize the carbon costs that NWE has included in its analysis of the relative value of the alternative electric supply portfolios?

A. Dr. Wilson terms those carbon costs a "carbon tax" approximately 70 times in his direct testimony. (E.g. p.9 at 20, p.12 at 13 and 14, p.14 at 15, etc.) He also emphasizes that they are *potential future* costs by referring to those costs as "hypothetical" carbon costs over a dozen times. (E.g. p. 16 at 10, p. 17 at 6 and

13, footnote 10, etc.) He repeatedly emphasizes that we do not know if such costs associated with the regulation of carbon will ever materialize.

Q. Is a “carbon tax” the only way that the regulation of carbon emissions may impose costs on utilities and their customers?

A. Obviously not. The U.S. Energy Information Agency (EIA) statement in this regard, which is relied on by Dr. Wilson, makes this clear. Dr. Wilson quotes the U.S. Energy Information Administration (EIA) twice as characterizing its inclusion of a carbon cost in its modeling of future U.S. energy markets as “hypothetical carbon dioxide…emission fees…[to] illustrate the impact of policies that might place an implicit or explicit value on CO2 emissions from fuel combustion.” (p. 17 footnote 9, p. 43 at 21 and p. 44 at 1-2)

Note, in this regard, that EIA is using a carbon dioxide emission fee as a stand-in for the potential impact of policies that might impose a cost on CO2 emissions from burning fuels, even if that impact is an indirect result of those carbon control policies, i.e., is something other than a “carbon tax.”

There are a variety of ways in which the regulation of carbon emissions can impose costs on utilities and their customers. All of that regulation of carbon emissions is not in the future. The U.S. Environmental Protection Agency (EPA) has already proposed rules regulating the carbon emissions from new electric generating facilities and is now developing rules regulating the emissions of carbon from existing electric generators. At present, this federal regulation of carbon emissions in not taking the form of a carbon tax, but it will be imposing costs on electric utilities and their customers. The rules governing new electric generators require carbon emissions to be approximately at the level associated with a natural gas-fired combined cycle combustion turbine (CCCT). Coal-fired electric generators could meet these rules only by investing in carbon capture and sequestration (CCS), a technology that is struggling to gain industry acceptance. Alternatively, Integrated Coal Gasification Combined Cycle (ICGCC) technology *may* meet those carbon emission standards but also at a relatively high and uncertain cost.

The result is that the cost and risk of building a new coal-fired electric generator that can be permitted has risen so high that almost no such plants are planned or expected to be built in the foreseeable future. As is well known in the industry, utilities are turning to natural-gas fueled CCCT's despite their higher operating costs compared to coal-fired generators. The impending regulation of carbon emissions of existing electric generators using fossil fuels will also impact the cost structure electric utilities face. EPA may allow regional trading of carbon emissions from those plants in order to reduce the cost of reaching overall carbon emission targets. That could result in a price being assigned to those carbon emissions.

In addition, uncertainty about future regulation of the emissions from coal-fired generators, including carbon emissions, has led electric utilities to retire an increasing number of their older generators. State policy has also put pressure on the operators of coal-fired generators in Washington and Oregon (Centralia and Boardman) to plan the early retirement of those plants. Washington's Utilities and Transportation Commission is also raising questions about the wisdom of relying on importing electricity produced by coal-fired plants outside of Washington, most notably in Montana, to meet their citizens' electric demand.

A "carbon tax" is not the only way in which the regulation of carbon will impact utility costs. For simplicity of modeling rising costs associated with carbon regulation, one can treat the potential costs as an "adder" associated with the combustion of fossil fuels, but that is a stand-in for a variety of possible cost impacts associated with carbon regulation. Many economists and regulators at the federal and state level expect carbon regulation to ultimately take the form of an explicit price placed on carbon emissions because this is believed to be the most flexible, effective, and efficient way of regulating those emissions. But currently, EPA is emphasizing traditional regulations that limit carbon emissions at particular facilities.

It is important to also note that even future and uncertain carbon emission regulations impose costs *now* on electric utilities. So, for example, utilities are retiring older coal-fired plants, replacing them with natural gas generation.

It would be seriously imprudent from a business point of view for an electric utility to make investments in long-lasting electric generating facilities fueled by carbon-intensive fuels while ignoring the risks associated with the future potential regulation of carbon. Uncertainty about the future timing and costs of such regulation does not mean that utilities should assume that uncertainty and risk about the costs associated with regulating carbon emissions do not exist and proceed with investment decisions as if those risks were zero. Calling those potential costs "hypothetical" and pointing out that they might not actually be realized does not mean that an assumption of a zero cost is the correct business planning assumption.

The Commission's rules for electric supply procurement make clear that such risks must be incorporated systematically in electric supply procurement decisions now as those decisions are made. The risk of costs associated with the ongoing regulation of carbon emissions has to be part of the decision making.

If NWE were to currently build a new coal-fired electric generator without any carbon-emission controls and ask this Commission to add it to NWE's ratebase, committing customers to repaying the cost of constructing and operating that plant, this Commission would surely ask serious questions about the wisdom of building such a plant given the clear risk of costs associated with federal regulation of carbon emissions. Whether one thought that such federal or state carbon regulation was appropriate or not, the fact that it might be adopted and new plants would have to comply or not operate at all would create a real risk that a prudent utility (and Commission) would have to take into account in evaluating such an investment decision. Most electric utilities, of course, are doing exactly that. Most electric utilities are choosing <u>not</u> to invest in additional coal-fired generation.

Just as any utility contemplating the construction of a coal-fired electric generator <u>has</u> to take into account the future costs associated with the regulation of the emissions from such a plant, a utility contemplating the acquisition of an electric supply facility that did not have those same potential costs associated with carbon emissions would also have to incorporate that particular economic advantage into its financial analysis and decision making. Of course this is not the only source of uncertainty associated with a utility's choice of a generating technology and fuel. All of the other characteristics of that supply source, both positive and negative, would have to be included in the analysis. But it certainly would be imprudent to purposely ignore one of the key economic characteristics of that particular supply source.

Q. Dr. Wilson asserts that NWE's hydro purchases proposal has the effect of embedding speculative future carbon costs immediately and irretrievably into customers' rates that then will have to be paid indefinitely into the future by customer whether or not those carbon costs ever become a reality. He describes this as forcing customers to "pre-pay" "carbon taxes" that do not exist and may well never exist. Is this an accurate description of what NWE is proposing?

A. As discussed above, labeling these projected costs associated with regulation of carbon emissions a "carbon tax" is more a rhetorical flourish than an analytical statement.

Leaving that issue aside, the accuracy of Dr. Wilson's characterization of the NWE's proposed hydro purchase can be judged by applying this approach to, say, reliance on market purchases in a quite different hypothetical situation.

Assume, hypothetically, that the regional electric market was projected to tighten considerably for a variety of possible reasons such as

i. The retirement of aging coal-fired electric generators.

ii. The commitment of more of the region's hydroelectric generation to support a growing fleet of wind electric generators.

iii. Increased competition from Alberta for electric supply available from Montana.

Also assume that natural gas prices were expected to rise significantly. If the marginal generating units in the region whose operating costs determine the market electric prices are natural gas fueled, then market electric prices could be expected to rise too. Hypothetically, those rising natural gas prices might be tied to a variety of events:

i. Increased exports of U.S. natural gas in liquefied form (LNG) to the rest of the world.

ii. Higher costs and lower productive lives for hydraulic fracturing of shale gas formations than had been expected.

iii. Increasingly costly regulation of hydraulic fracturing including stricter control of methane emissions.

Also assume that there is no public or government concern about the carbon emissions from electric generators

In that hypothetical setting, it might be possible for NWE to demonstrate that reliance on regional electric markets was a very high cost and risky strategy. Similarly, in such circumstances, investment in a natural gas fueled CCCT also might look like a high cost and risky strategy. The purchase of PPLM's hydroelectric units might appear to be the supply strategy that had the lowest cost and lowest risk.

Following Dr. Wilson's approach in characterizing the hydro purchases actually at issue in this docket, a proposed hydro purchase in this hypothetical setting might be characterized in the following manner:

> The proposal to rate base the cost of the hydro purchase will immediately and irretrievably embed speculative future natural gas and electric prices into customers' rates. Customers would have to pre-pay the utility's guesses about future natural gas prices and would have to continue to pay rates tied to those speculative natural gas prices indefinitely into the future even if those high natural gas and electric prices were never realized. This amounts to taxing customers indefinitely into the future based on speculation about future natural gas prices.

Alternatively, consider another electric supply decision the utility might make: NWE choosing to build a natural gas fueled CCCT because the hydro purchase opportunity was not available. NWE's more recent Electric Supply Resource Acquisition Plans have seen such a CCCT as the most attractive alternative for additional generation. Most other utilities around the nation have come to similar conclusions, planning investments in the same technology to supplement supply.

Assume that the life-cycle costs of the CCCT and coal-fired generator at the time were similar except for potential costs associated with regulation of emissions from the two types of plants.

If NWE were to bring such a resource to this Commission, it would be expected to explain why, given all of the coal that Montana has and regional utilities' previous commitments to coal-fired generation, NWE was not proposing a new coal-fired generator. In that hypothetical situation NWE would likely respond that the costs associated with increasing regulation of the emissions associated with new coal-fired generation were much too high to justify such a large and long-lived investment. There might also be risks associated with reliance on leased federal coal. NWE would likely point out that the regulatory risks associated with natural gas fueled generation appeared much lower.

To the extent that such justifications were given for the choice of a natural gas fueled CCCT over a coal-fired generator, it could be said that customers were being asked to pay higher rates immediately and on into the future based on hypothetical regulation of coal combustion emissions that were not on the books yet and might well never be on the books. Customers, it could be said, were being asked to pay a tax indefinitely into the future based on the utility's feared federal regulation that was entirely speculative. Customers were being forced to pre-pay for regulatory costs that might never be imposed.

The point of these hypothetical examples is simply that in every resource supply decision that a utility makes, it compares projections of future prices, costs, technological changes, regulatory rules, engineering reliability, etc. On the basis of the analysis of those *assumptions* or *projections* about the future, utilities incur fixed costs that if embodied in rates will "burden" customers indefinitely into the future. Customers unavoidably have to both "prepay" and have to carry the investment cost "embedded" in their rates. That is the characteristic of a capital investment.

Of course, the utility can avoid making such commitments to capital investments or long-term fixed contracts in supplying their customers by choosing to rely entirely on short-term purchases. That, of course, carries the potential for a whole different set of costs to customers, including the electric market risks discussed in the testimony above.

In general, fixed investments involve making an upfront commitment of a large amount of money to a particular technology, a stream of purchases over the years for the inputs used by that plant, and a particular variable market and variable stream of market prices for the output of that plant. There is risk in all of this. That does not mean that in general fixed investments are unwise and should be avoided.

3. Dr. Wilson's Primary Reliance on the Deterministic DCF Modeling

Q. On what analytical approach does Dr. Wilson primarily rely in his criticism of including the proposed hydro purchase in NWE's electric supply portfolio?

A. He relies almost exclusively on the Discounted Cash Flow model that seeks to track all of the costs and revenues associated with a particular supply portfolio or particular source of supply and then discount the net costs or net benefits back to the present. To carry out that sort of analysis one has to assume that we *know* the values that dozens of economic variables will take on twenty to thirty years into the future. That is why this type of modeling is call "deterministic." All risk and uncertainty about what values all of those economic variables will actually take on in the future is assumed away. That, of course, has the advantage of dramatically simplifying the analysis. It also has the disadvantage of grossly misrepresenting the actual economic circumstances in which a resource supply choice has to be made.

Q. Are you saying that uncertainty cannot be considered if one uses DCF modeling?

A. No, not at all. The analysis can carry out "sensitivity" analysis in which economic variables to which the DCF modeling outcomes may be particularly sensitive can be varied to higher or lower levels to see how the model results change. That can provide some feeling for the uncertainty and risk associated with particular assumptions.

This is typically done by choosing high and low values as well as “expected” or “most likely”) values for the more important economic variables. How accurately this reflects the actual risks depends on how appropriate those alternative values are in reflecting the actual range of uncertainty and whether some information about their likelihood of occurring can be provided.

Often parties with different interests pick and choose among alternative high, low, and most-likely values and the range of projected outcomes becomes very large and difficult to interpret.

Stochastic analysis cannot completely avoid these problems. But it does try to build the uncertainty about the values of the most important variables and an understanding of their frequency distribution directly into the evaluation of alternative electric supply portfolios. In that sense, more information is introduced into the modeling, allowing it to more accurately represent the resource supply decisions in the context of uncertainty.

Q. Is it unusual to use a DCF model to evaluate a potential investment?

A. Certainly not. NWE and its financial advisor, Credit Suisse, both used DCF models as *one* of the tools to analyze the value of PPLM’s hydroelectric resources in Montana. Dr. Wilson used NWE’s DCF model, modifying several of NWE’s assumptions.

Q. How does Dr. Wilson use NWE’s DCF model?

A. He attempts to use it to support two of his major conclusions, namely that

i. NWE's carbon cost assumptions inflated the price NWE offered to pay for the hydros, for which NWE is asking customers to take responsibility.

ii. The hydro purchase is very costly compared to simply relying on market purchases.

Q. How does Dr. Wilson link NWE's DCF model to the price NWE offered to pay for the hydros?

A. Dr. Wilson asserts the following about the NWE DCF modeling: "This DCF analysis was used by the Company [NWE] to develop and support its bid for the hydros, when it was essentially dealing with PPL on behalf of Montana ratepayers." P. 35 at 4-6.

It certainly is true that NWE used its DCF modeling to "develop and support its bid for the hydros." But Dr. Wilson proceeds to assume that NWE relied primarily on the DCF model to determine what price to offer PPLM for the hydros, Dr. Wilson is then able to change assumptions in the DCF model and calculate how assumptions Dr. Wilson does not believe are defensible effectively inflated the price for the hydros that NWE is asking customers to pay.

Q. Is it your understanding that NWE primarily used the DCF modeling to determine what it should offer PPLM for the hydros?

A. No. As NWE makes explicit, DCF modeling was *one* of the tools NWE used in evaluating the hydro purchase.

As NWE witness Stimatz put it in his direct testimony (p. JMS-4): "The DCF valuation was one of many pieces of information available to NorthWestern's executive team to aid their decisions regarding the ultimate bid." He refers back to NWE CFO Brian B. Bird's direct testimony.

NWE witness Travis E. Meyer made the same point: “As discussed in more detail in the Bird Direct Testimony, NorthWestern utilized several internal and external data points to arrive at the agreed-upon $900 million purchase price in the acquisition of the Hydros.” (p. TEM-5 at 1)

Mr. Bird discusses the use of the DCF model to determine what a merchant generator might be willing to pay to purchase the hydros (p. BBB-14). That was used to indicate what NWE might have to be willing to pay in a competitive bid for the hydros. However, Mr. Bird lists at least a half-dozen other sources of information on which NWE relied in making its bid for the hydros including:

i. Other utilities evaluations of the hydros (p. BBB-4);
ii. Credit Suisse’s valuation analyses including its own DCF analysis, a comparative asset value analysis, and a comparison with the cost of alternative new build alternatives (p. BBB-17);
iii. Blackstone Advisory Partners’ fairness opinion of the price that might be paid for the assets (p. BBB-18);
iv. An analysis of the potential initial rate impact associated with different purchase prices (p. BBB-15).
v. A long-term revenue requirement analysis of the rates that would be necessary to support a purchase price (p. BBB-15).
vi. PPLP’s rejection of the initial NWE bid of $740 million for the hydros as “way too low” (p. BBB-8).

Q. Are you saying that NWE did not use its DCF modeling to help establish the price it offered PPLM for the hydros?

A. No. I am simply saying that the NWE DCF analysis at the time was not the only or even the primary consideration that supported its ultimate offer price. We, of course, know that was not the case since NWE originally offered $740 million for the hydros. That bid was rejected by PPLM. NWE was involved in a bidding strategy seeking to find the lowest price at which it could acquire the hydros given the value it thought the hydros could contribute to its electric supply portfolio going forward. In that setting, it is not correct to suggest that one model run dictated the price that would be bid for the resource.

Q. Are DCF modeling results from that bidding period the only or primary measure that should be used to evaluate the proposed hydro purchase?

A. No. First of all, as discussed above, that DCF modeling was never the only or primary analysis that NWE undertook in evaluating the hydro purchase. Second, the question before this Commission is whether the proposed hydro purchase will benefit customers more than alternative ways of supplementing NWE's electric supply portfolio.

Additional analysis of the proposed purchase has been undertaken since NWE's initial DCF modeling. That includes the analysis carried out for NWE by Ascend using the PowerSimm model that moved beyond the deterministic DCF modeling and explicitly recognized the uncertainty and risk surrounding many of the variables that DCF modeling takes as known and fixed. The PowerSimm modeling provides a more sophisticated approach that makes use of more information about the character of the uncertainty that utilities face when making electric supply portfolio decisions.

Dr. Wilson, however, primarily relies on NWE's DCF modeling. This reliance solely on the more primitive valuing technique is useful to Dr. Wilson because it allows him to continue to act as if future electric market prices and natural gas prices are know with certainty, as are all the other economic variables that combine to make up the uncertain and risky future economic context in which the chosen electric supply portfolio must function.

Since Dr. Wilson has conceptually waved away the primary sources of uncertainty and risk that lead electric utilities such as NorthWestern to choose one source of supply over another, Dr. Wilson can continue to assume that he and we know exactly what future electric market prices will be. This allows him to use “the competitive market” as a firm, reliable, and low-cost source of future electric supply. With that assumed knowledge, some of the major concerns electric utilities like NorthWestern seek to resolve through integrated resource planning simply evaporates and assumed fixed and known electric market prices can be used as the sole reference point when evaluating alternative source of supply.

This is certainly is a massively simplifying assumption: We are assumed to know the future and, because of that, the choice of an incremental supply source becomes infinitely simpler. Analyzing resource choices in an assumed deterministic world can be useful in initial resource analysis, but it is not sufficient for actually making fully informed real world choices.

4. Residual Plant Value and Depreciation

Q. Dr. Wilson objects to NWE’s inclusion of a $1.7 billion residual value of the hydros at the end of the 30-year stochastic modeling period. He repeatedly suggests that this assumed *increase* in the value of the hydros conflicts with the assumed *decrease* in the value of the hydros that is associated with ongoing depreciation. (p. 6 at 14-16; pp. 27-28 at 1-2 and footnote 12) Is NWE being inconsistent in assuming both that the hydros are declining in book value over the years due to depreciation and are also increasing in market value with the passage of time?

A. No. Dr. Wilson is ignoring the function of depreciation and the function of estimating a residual value when a capital investment is analyzed over an arbitrary fixed period of time that is shorter than the expected productive life of the ongoing operation.

Depreciation is part of the return on investment to investors. Investors do not just want to earn a return on the money they put up. They also want to recover their original investment. The full return to investors is the return *on* the investment and the return *of* the original investment. Dividend payments or appreciation in the value of the stock provides the return *on* the investment. Depreciation provides the return *of* the original investment.

In an ongoing business enterprise that plans to operate indefinitely into the future, the business will be carefully maintaining its capital plant and equipment so that its productive capacity does not deteriorate. Much of this is done with *maintenance* expenditures that regularly support ongoing preventative treatment of capital equipment, repairs, rebuilds, and other steps that will allow the plant to continue to operate. If some equipment or plant has to be replaced, a new capital investment may be made (CapEx) which will be added to the books and be depreciated on its own over time.

If this process of maintenance and capital replacement is successful and the productivity of the plant and equipment is maintained, then at the end of any given period of time, the plant and equipment in place will continue to have a value dictated by the net cash flow it can produce over future years. It will have this value no matter what the original depreciation account says about stockholders' recovery of their original investments.

If this ongoing productive value is expressed in nominal future dollars (as opposed to dollars of current fixed purchasing power), the economic value of the productive plant and equipment will appear to have increased. In NorthWestern's case, that value is allowed to increase at the rate of inflation, meaning that in inflation adjusted ("real") terms that value was not really projected to increase at all. That should not be a startling outcome if over the years of the analysis period appropriate maintenance and CapEx expenditures have been undertaken so that the plant and equipment can continue as a productive part of an ongoing business.

However, during the time period of analysis the depreciation balance may well be systematically falling as the original investment is returned to investors following a linear formula (straight line depreciation) or a much more rapid return (various accelerated depreciation schedules allowed by the tax code). This declining depreciated value will be somewhat offset by the additional depreciation associated with equipment that has been replaced.

There is no logical inconsistency in the economic value of an ongoing business being maintained over time while depreciation costs continue to be recorded on the company's books.

5. The Dangers of Utility Investors Seeking a Return on Their Investment

Q. Dr. Wilson is quite critical of the hydro purchase price of about $900 million that NWE ultimately offered PPLM and PPLM accepted. What is the basis for Dr. Wilson's concern?

A. Dr. Wilson is concerned that NWE has purposely inflated the price it offered to pay for the hydros. For instance he says,

> …it cannot necessarily be assumed that NWE had great incentive to minimize the price bid if the resulting purchase price goes into the Company's rate base and increases stockholder profits on a preapproved basis. (p. 35 at 7-10)

In a similar vein Dr. Wilson asserts:

> …there is little doubt that the virtually risk-free proposed addition of $900 million to NWE's rate base is a great profit opportunity for the Company, as Montana consumers will be required to compensate NWE for those costs, plus hundreds of millions in associated profits for decades, regardless of whether the acquisition turns out to be a good deal for *rate payers.* (p. 14 at 20-21 and p. 15 at 1-4, emphasis in the original)

Q. What is your understanding of the basis of Dr. Wilson's concern about NWE having an incentive to inflate the purchase price of the hydro to boost stockholders' profits?

A. Dr. Wilson's concern seems to be tied to two assumptions.

First, as discussed earlier in this testimony. (See Section 1, pp. 2-10 above), Dr. Wilson's point of comparison is NWE's continued heavy reliance on electric market purchases at a known and certain price. This makes the reliance on the market appear to be risk free. Since NWE does not earn a return on its market purchases but would earn a return on the investment in the hydros (or any other generating facility it owned), it is possible to suggest that NWE chose the purchase of the hydros because it was the alternative on which its stockholders could earn a return.

Second, Dr. Wilson seems to assume that this Commission fails to set NWE's allowed rate of return on equity at a competitive market level for investments of similar risk. This also implies that Dr. Wilson and the Montana Consumer Counsel are ineffective in helping establish such a market-based cost of equity. Only that would explain why stockholders would prefer to pour their dollars into over-priced utility assets.

Q. Is it startling and unusual for electric utilities to raise equity and debt capital and invest it in plant and equipment including electric generators?

A. Of course not. That is what an Investor Owned Utility (IOU) does. Actually, it is what most publicly-owned and cooperative electric utilities do too. Paying investors for the use of their capital so that plant and equipment can be put in place to serve customers is not usually considered some sordid anti-consumer act. Repaying the bond holders with interest or rewarding equity investors with dividend payments and increases in stock values are also not usually considered evidence of investors exploiting utility customers.

The fact is that a return is earned by investors that help finance any electric generator that is built. Those payments are not usually considered unfair extractions. In fact such long-run investments are usually treated as a positive commitment to the future.

Q. Does the fact that utilities do not usually earn a return on their electric market purchases mean that customers, in general, would be better off if electric utilities did not invest in electric generation?

A. No. This was discussed in the testimony above. See pages 5-10 above. Simply buying electricity on the market and making no investment in generation appears to be a "no-brainer" in Dr. Wilson's analysis because he has assumed that there is no electric market risk either in price or delivery. Yet electric utilities invest in generation partially to avoid the very risk Dr. Wilson assumes away. Such investments can be in customers' interests, not just a sign of a rapacious utility.

Q. Dr. Wilson points out the profits that NWE stockholders will earn as a result of this transaction. Is that evidence of NWE taking advantage of its customers?

A. No. Dr. Wilson carefully focuses on the total number of dollars that customers will have to pay to investors over the next thirty years to cover the cost of capital. Alternatively he talks about the hundreds of millions of dollars that investors will earn on their investments in NWE.

Typically a return on investment is labeled high or low not because of the total number of dollars being returned to investors but on the basis of what the percentage return on investment is. The revenue flow back to investors is partially tied to how large the investment was that had been made. To tell if the investors are "making a killing," one has to calculate the percentage return on total investment. That could be very low and there still could be a very large flow of revenue back to the investor if the overall investment was large.

Q. Does NWE set the rate of return on investor equity that is included in customers' rates?

A. No. The Montana Public Service Commission, often with Dr. Wilson's help, sets that return on equity. Well established principles of regulation require that return on investment to be based on what other investors in a market setting are earning on their investments after adjusting for differential risk.

If the Montana Public Service Commission is doing its job well (with Dr. Wilson's help), investors are earning no more than they could earn elsewhere in the economy for an investment of similar risk. For that reason there is no reason to believe that investors are stampeding to invest in NorthWestern so that they can earn an above market rate of return. They should be indifferent between investing in NorthWestern and investing elsewhere in the economy.

If the Montana Public Service Commission has been setting the authorized return on equity too high, then it could be creating a perverse incentive for NWE to over-invest in the utility. That seems unlikely. But if that is the situation, then the first step to resolving the problem and align the interest of the utility with those of its customers on the investment issue is to make sure that the return of equity is set correctly.

Q. But some theoretical economic analyses concluded that in certain circumstances regulated investor-owned utilities may have an incentive to over-invest in the utility in order to earn more than they could earn elsewhere, driving customers' rates higher than they would be if this over-investment had been prevented. Could this be the mechanism behind Dr. Wilson's concern that NWE had an incentive to pay a higher price than was necessary for the hydros?

A. Possibly. If that is the case, however, I have problem with it.

In the early 1960s Harvey Averch, Leland Johnson, and Stanislaw Wellisz (AJW) theorized that if a firm was subject to rate of return regulation and the rate of return was set above the firm's cost of capital, there could be an incentive for the utility to choose a more capital intensive and less labor intensive production technology. This came to be called the A-J or AJW effect. In more popular terms, in the very particular theoretical circumstances laid out, the utility might "gold plate" its investments.

Over the last half-century economists have investigated whether there is empirical evidence supporting the reality of this theoretical insight, i.e. is there empirical evidence that this over-investing behavior actually takes place to a significant extent within regulated industries like electric utilities. In 2005 MIT Professor Paul Joskow, a leading national energy economist and expert on regulated industries, published a review article on "Regulation and Deregulation after 25 Years."[1] His conclusion about the usefulness and applicability of the theoretical AJW effect was as follows:

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[1] "Regulation and Deregulation after 25 Years: Lessons Learned for Research in Industrial Organization," *Review of Industrial Organization,* 2005, 26:169-193.

> In my view, students of regulation of legal monopolies wasted at least 15 year extending the Averch-Johnson model of regulatory behavior and trying to test it empirically without much success (Joskow and Rose, 1989). The Averch-Johnson model and its progeny have been replaced with a richer set of models of regulation, both normative and positive, that consider asymmetric information, political economy considerations, legal constraints on agency behavior and their effects on the incentive properties of regulator mechanisms and ultimately on the behavior and performance of regulated firms. (p. 188)

In 2008 there was another review "Assessing Evidence for the Averch-Johnson-Wellisz Effect for Regulated Utilities." It concluded that "In general, there is little evidence to suggest that there was ever an AJW effect."[2]

Given the overall failure to empirically document the reality and significance of such a tendency for regulated utilities to over-invest in capital equipment *because* of rate of return regulation, any appeal to that theoretical possibility would be misplaced and unreliable.

Q. Are there incentives for the utility to pay attention to the costs it incurs in providing electric supply to its customers?

A. Yes. For instance, if the Commission determines that the proposed hydro purchase is too costly, the proposed purchase could be rejected, a frustrating and embarrassing outcome for the leadership of NWE. Similarly, if the utility appears to be regularly making questionable electric supply judgments, it can

[2] Stephen M. Law, Economics Department, Mount Allison University. Paper presented at the 36th Atlantic Canada Economics Association, 2008, Abstract. http://economics.acadiau.ca/tl_files/sites/economics/resources/ACEA/Papers and Procedings/2008/S.Law.2008.pdf

expect stricter regulation by the Commission with the possibility of expensive disallowances of costs. The Commission is not helpless in monitoring and disciplining the utilities under its jurisdiction.

It is true, however, that under cost of service regulation with energy supply cost trackers and no profit associated with electric market purchases, the incentive system is not optimal from either the Commission's or the utility's perspective. That is one of the reasons that the regulatory atmosphere often is fraught with tension. Working to develop regulatory policies that align utility incentives with Commission objectives is obviously appropriate. So is making utility and Commission decision-making more transparent so that everyone understands the "rules of the game" and how they are being applied. But some of the tension between regulators and the regulated company is simply part of the consequences of the regulatory system we put in place to protect the public from the wasteful and inequitable exercise of market power by utilities who are the sole market players in their service territories.

Q. Does that complete your response testimony?

A. Yes it does.